Experimental Study on the Effect of Nano-silica on Mud Density in Synthetic Based Mud

by

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13779

Dissertation submitted in partial fulfilment of
the requirements for the
Bachelor of Engineering (Hons)
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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
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Approved by,

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Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
MAY 2014

CERTIFICATE OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgments, and that the original work contained herein have not been undertaken or done by unspecified sources or person.

CLAIRE CHANG LI SI

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ABSTRACT

Drilling fluids play important roles in drilling operations to suspend cuttings, counter high formation pressure and to ensure wellbore stability. Amongst the different types of drilling fluids, currently synthetic based muds are the choice drilling fluid due to its high performance in HPHT wells in terms of wellbore stability and high penetration rates. However, under HPHT conditions, the well will encounter thermal degradation of mud properties, which will affect the performance of the mud, such as fluid loss, unstable rheology and barite sag. Barite sag is an effect of high density and high solid content in muds, in which the heavy solids in the mud settle at the bottom of the wellbore causing pipe sticking and lost of circulation. The experiment was carried out at LPLT, starting of HPHT and extreme HPHT conditions with a varying nano-silica concentration of 0%(base case) to 40%. At different mud weights, the formulated drilling fluid will be tested for HPHT filtrate loss, stable rheology and static sag at a 45° tilt. Nano-silica has been proven in this project to be only effective for fluid loss and improve mud rheology due to the nature of nano-silica as a plugging agent. The nano-silica had no effect on barite sag as proven in this experiment. Nevertheless, the newly formulated mud is still effective for solving and preventing downhole problems.

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CHAPTER 1

1.0 INTRODUCTION

1.1 Background

Drilling fluids, also known as drilling mud, functions to suspend cuttings, control pressure, stabilize exposed rock, provide buoyancy, cool and lubricate the drill in the well (Tran, Soong, Martello, Rakesh, & Agharwal, 2011). During the third century BC, the Chinese had already been using drilling fluids (Jesil, Mohiuddin, Ruqeshi, Geetha, & Mohataram, 2013). The drilling fluids used then were water based, to assist in permeating the earth when drilling for crude. The term “drilling mud” was only conceived when at Spindle top in the United States. In a watered down field, drillers ran a herd of cattle through and used the ensued mud to lubricate the drill.

Cuttings are present in the wellbore as a result of drilling. They are not a concern until drilling stops due to drill bit failure (Cho, Subhash, & Samuel, 2001). This is a complication as the cuttings are not being circulating, and will fill the hole again. Drilling fluids function as a suspension tool to prevent such situations (Nazari & Hareland, 2010). Drilling fluids have non-Newtonian properties, therefore when movement decreases, the viscosity of the drilling increases (Saasen, et al., 2009). This allows the fluid to possess liquid consistency while drilling, and become thicker like a solid substance when drilling has stopped. The fluid will then serve its purpose of suspending cuttings till the drilling resumes (Omland, et al., 2006).

Apart from that, drilling fluids aid in pressure control in a well by offsetting the pressure of hydrocarbons and formation (Nygaard & Breholtz, Advanced Automatic Control for Dual Gradient Drilling, 2009). Formation pressure needs to be counterbalanced to achieve overbalanced/underbalanced conditions in the wellbore. This will prevent formation fluids (such as oil, gas, and water) from entering the well prematurely, which may lead to a kick/blowout and prevent the well from caving in

(Nygaard, et al., 2007). Another factor for using drilling fluids is rock stabilization. Certain fluid additives are used so that fluid will not be lost to formation pores and clog pores (Jung, Zhang, Chenevert, & Sharma, 2013). A deeper well will require a longer drill pipe, which will cause it to weigh heavier. Consequently, drilling fluid adds buoyancy, reduces stress, and helps to reduce friction with rock formation. Hence, reducing heat, lubricating to prolong the life of the bit and aid in hole cleaning (Noui-Mehidi & Amanullah, 2010) (Saboori, Sabbaghi, Mowla, & Soltani, 2011).

1.2 Problem Statement

At High Pressures and High Temperatures (HPHT), drilling operations are very challenging. In terms of drilling fluid, the designed mud weight must be higher in HPHT wells, and needs to be accurately controlled in narrow mud windows. Due to this requirement, the difficulties that arise will be high solid loading and barite sag. High solids loading with resulting higher pressures and rock incompetency at deeper depths lead to low rate of penetration (ROP). Apart from that, at HTHP conditions, the mud system degrades and becomes unstable at high-pressure high temperature (HPHT) conditions, causing fluid loss from mud. Fluid loss is an effect of mud cake not being able to form on the walls of the formation, which will lead to a decrease in hydrostatic pressure in the wellbore, hence a kick can occur. Therefore, there is a need in the oil and gas industry to enhance current conventional mud systems with effective fluid loss control agents, rheology modifiers and weighing agents.

1.3 Objective

The main aim of this project is to study the effectiveness of nano-particles, mainly silica, as an additive to synthetic based muds to the extent of HPHT conditions. The objectives are:

- To improve performance of synthetic based mud with silica nano-particles
- To investigate the effect of nano-silica on mud density

- To investigate the quality of silica nano-particles as a fluid loss agent and rheology modifier

1.4 Scope of Study

The study will focus on testing varying mud densities on mud performance at different parameters such as:

- Mud Density
    - 12ppg
    - 13.5ppg
    - 17ppg
- Temperature ranging from 275°F to 450°F
    - At 275°F (lower temperature)
    - At 350°F is considered the starting point of HPHT conditions
    - At 450°F, the study aims to investigate the SBM at extreme HPHT conditions
- Size of nano-silica particles
    - 10-20nm
- Concentration of nano-silica replacing conventional fluid loss agents
    - 0% - 40%

Hence, overall the controlling parameter is mud density, as this study aims to investigate the effect of nano-silica on barite sag, which is an issue caused by high mud density.

CHAPTER 2

2.0 LITERATURE REVIEW

2.1 Synthetic Based Mud (SBM)

Synthetic based muds are non-aqueous, water internal (invert) emulsion muds in which the external phase is a synthetic fluid rather than oil (Glossary, 2014). The aim of a synthetic based drilling fluid is to be environmentally friendly for offshore use. The base fluid can be a hydrocarbon, ether, ester or acetal (Neff, McKelvie, & Ayers, 2000). An example of synthetic fluids, which were used in the Gulf of Mexico, is linear alpha olefins (LOA), isomerized olefins (IOs), polyalphaolefins (PAOs) and esters (Omland, et al., 2006). The other ingredients of a synthetic based drilling fluid includes:

- Emulsifiers
- Barite
- Clays
- Lignite
- Lime

Synthetic based muds have many advantages, and are currently the drilling fluid choice for drilling operations in deep-water environment because of its ability in accomplishing high rates of penetration and maintaining wellbore integrity (Lee, Friedheim, Toups, & Oort, 2004). SBMs can achieve wellbore stability because the synthetic liquid forms the continuous phase while brine serves as the dispersed phase. During drilling operations, the solids in the mud system and the formations are primarily exposed to the synthetic liquid and not to the aqueous phase, preventing swelling and degradation of borehole walls (Burke & Veil, 1995).

As for high penetration rates, invert emulsion fluids improves hydraulic cleaning efficiency in hole intervals, which inherently increases penetration rates (Burke & Veil, 1995).The fluid prevents cuttings from adhering to the bit and hole surfaces. Therefore, there will be an increased rock bit performance, and less hydraulic horsepower is needed to ensure efficient wellbore cleaning. Adequate salinity in the emulsified fluid also provides sufficient osmotic pressure to stop water absorption as absorbed water causes cuttings to stick to each other, to the bit and to the hole surfaces, thus, causing the need for high hydraulic horsepower for turbulent scrubbing for hole cleaning.

2.2 Effect of Mud Density on Mud Performance

Mud weight is an important parameter in designing any drilling fluid. This parameter correlates with bottom hole pressure in the wellbore. Mud weight must be sufficient to transport cuttings to the surface, and maintain wellbore stability from caving or breakout (Swanson, Munro, Sanders, & Kelly, 2000). Higher down hole pressures equal to a higher mud weight requirement. Common weighing agents such as barium sulphate (barite) are used to achieve higher mud weight.

2.2.1 High Pressure High Temperature (HPHT) Conditions

A HPHT well has been defined by United Kingdom Continental Shelf Operations Notice as any well where the undisturbed bottom hole temperature is 300°F or greater and either the pore pressure exceeds 0.8 psi/ft or pressure control equipment greater than 100,000 psi rates working pressure is required (Ogbonna, Boniface, & Ataga, 2012). Therefore, as mud weight is directly proportional to pressure, at HPHT drilling, a higher density drilling fluid will be required to withstand formation pressure (Ogbonna, Boniface, & Ataga, 2012). Normal mud densities are below 15ppg, whereas a drilling fluid is classified as having high mud weight when its density is above 15ppg.

2.2.2 Barite Sag

As mentioned before, at HPHT conditions, a higher mud density is required to withstand formation pressure. It occurs most in invert emulsion muds and can occur over a range of mud density from 11.7ppg to 20ppg (Tehrani, Popplestone, & Ayansina, 2009). Adding dispersed weight material such as barite can do this.

The addition of barite increases dispersed solids concentration, which increases drilling fluid viscosity, thereby creating a situation known as barite sag in drilling fluids. Barite sag occurs when heavier mud sags at the bottom while light mud remains in the upper part of the well (Dye, Mullen, & Gusler, 2006). It can be caused by static and /or dynamic settling followed by slumping of the weighted material (Amighi & Shahbazi, 2010).The effects of barite sag are wellbore instability, down hole mud losses and stuck pipe. The high loading of barite creates high-pressure losses during circulation in long sections, leading to unacceptably high equivalent circulating density in narrow drilling windows (Godwin, Boniface, & Ogbonna, 2011)

A number of factors listed below influence barite sag (Amighi & Shahbazi, 2010):

- Hole diameter
- Hole angle
- Wellbore length
- Annular velocity
- Drillpipe rotation
- Flow regime
- Mud viscosity
- Mud gel strength
- Fluid density
- Weighting agent density
- Particle size and shape
- Particle concentration and time

2.2.3 Static Sag

Static sag occurs when circulation stops for a period of time, and the weighting agents begin to settle under the influence of gravity (Tehrani, Popplestone, & Ayansina, 2009). The boycott effect is the settling of solids and is enhanced by convective currents created by density differences in the fluid across the annulus cross section (Amighi & Shahbazi, 2010).The boycott settling effect was found to be a major contributor to sag in drilling fluids (Omland, et al., 2006). The effect of static sag ranges from insufficient mud density for pressure control to the risk of fracturing the formation when suspending a barite bed (Saasen, 2002).

2.2.4 Dynamic Sag

Dynamic sag is the sag, which occurs while circulating mud (Saasen, et al., 2009). Primarily, sag was evaluated as and measured as static sag. However, recently, dynamic sag has been identified as a significant problem in drilling operations (Scott, Zamora, & Aldea, 2004). Dynamic sag is tougher to prevent as compared to static sag, as it does not correlate with conventional rheological properties. Instead, it is a function of low shear rate (Parvizinia, Ahmed, & Osisanya, 2011). Laboratory studies suggest that barite beds form while mud was circulating, thickened when flow was static and slumped (slid or oozed downwards) to create density variations in the fluid column (Zamora, 2009). Dynamic sag is amplified in deviated wells and under HPHT conditions (Dye, Hemphill, Gusler, & Gregory, 2001). To measure dynamic sag, a viscometer sag test device can be used where sag performance is investigated under (Tehrani, Cliffe, Williams, & Onwuzulike, 2011):

- Laminar flow conditions (dominant effect is fluid rheology)
- Flow loop (flow rate, eccentricity, pipe rotation and inclination are considered)

2.2.5 Conventional Methods to Reduce Barite Sag

- Alternate Weighting Material

Barite sag is a function of two physical properties of the weighing agent: size and weight of particle. Higher specific gravity weight materials such as ilmenite, manganese tetroxide (Carbajal, Buress, Shumway, & Zhang, 2009) and finely ground hematite (relative to barite) provide lower solids content at equivalent mud densities (Pless, Bland, Mullen, Gonzalez, & Harvey, 2006). During thru-tubing rotary drilling and HT/HP applications, the usage of these products resulted in lower abrasion of tubular goods, higher rates of penetration due to lower solids loading and lower pressure loss (Amighi & Shahbazi, 2010).

- Use Fine Weighting Agent Particles

A much finer particle will sag less quickly. Stokes Law defines this by:

Equation 1: Stokes Law

$$v = \frac{a^2(D_p - D_l)g}{18\mu}$$

Where:

v = Velocity (cm/s)

a = Particle diameter (cm)

D_p = Particle density (g/cm^3)

D_l = Carrying fluid density (g/cm^3)

μ = Carrying fluid viscosity/viscosity of the suspending medium (cp)

According to Amighi & Shahbazi (2010),

Table 1: Settling Velocity of a Single Particle in Water

Particle	D50	D_p (SG)	D_l (SG)	Settling Velocity(cm/day)
Barite	15	4.2	1	0.339
Hematite	15	5.2	1	0.445
Mn3O4	1	4.8	1	0.0018

Where;

D_p (SG) = Particle specific gravity

D_l (SG) = Carrying fluid specific gravity

D50 is D-value method used to describe particle size distribution. It is commonly used to represent the midpoint and range of particles in a given sample (Jienian & Wenqiang, 2006). D50 diameter is the diameter at which 50% of a sample's mass consists of smaller particles (Horiba, 2012). The D50 can also be known as the "mass median diameter" as the sample is equally divided by mass.

Since barite sag is directly influenced by size and weight of the weighing agent, a much finer particle will settle less quickly than a larger, similar weighed particle.

It can be observed from Table 1 that manganese tetroxide settles almost 200 times slower than barite in water (Amighi & Shahbazi, 2010). Indirectly, this confirms the major reduction in sag when using micro fine particles.

2.3 Usage of Nano-particles in SBM

Nanofluids for oil and gas field applications are defined herein as drilling, drill-in, completion, stimulation or any other fluids used in the exploration and exploitation of oil and gas that contain at least one additive with particle size in the range of 0.1-100 nanometers (Nabhani & Tofighi, 2012). Nanoparticles are defined as object with a diameter less than 100nm (Riley, et al., 2012).

High solids content in drilling fluids is one of the factors that attributes to wellbore instability, reduces productivity index and decreases penetration rates.As nano-based fluid needs small volume of nanoparticles due to their huge surface areas per unit volume, nano-based mud additive can dramatically reduce the desirable solids content of a mud with a significant increase in the ROP (Amanullah & Al-Tahini, 2009).

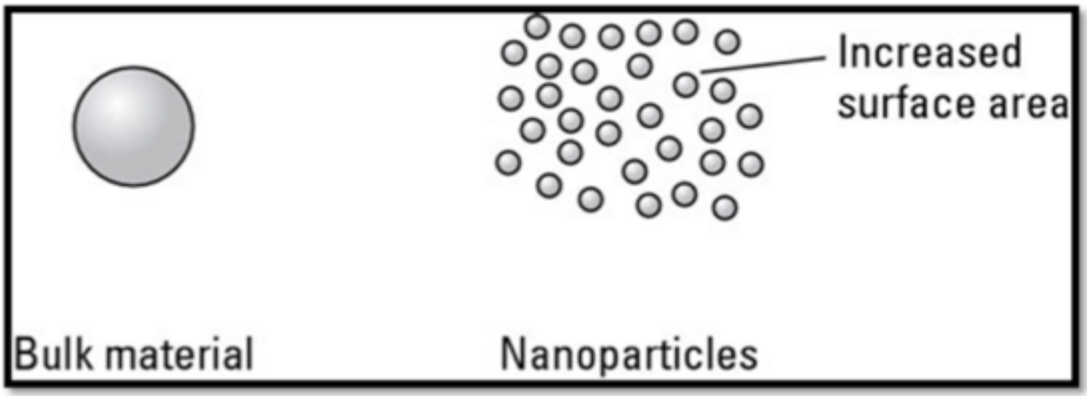

Figure 1: Comparison of Increased Surface Area of Nanoparticles, (Amanullah & Al-Tahini, 2009)

Besides that, nanoparticles also aid in fluid loss. Due to extremely fine particle sizes, that are smaller than pore throat sizes of shale and unconsolidated formations, it can easily inhibit shale- drilling fluid interactions. As shown in Figure 1, the extremely high surface area to volume ratio of nano-materials compared to the macro and micro materials of the same mother source provides them dramatically increased interaction potentials with reactive shale to eliminate shale-drilling mud interactions and the associated borehole problems (Amanullah, Al-Arfaj, & Al-Abdullatif, 2011).

2.4 Benefits of Nano-silica in Drilling Fluids

Silica, also known as, silicon dioxide is found in many different forms; amorphous/crystalline, porous and non-porous, anhydrous and hydroxylated. It is synthesized either by dissociating monomeric silic acid or from the vapor of a silicon compound, from aqueous solutions. Nano silica solutions are widely used, and come in sizes ranging from 5 to 100nm (Hendraningat, Li, & Torsaetor, 2013) (Long, et al., 2013). Adding sized silica to drilling fluids also inhibits filtrate invasion into formations, which cause formation-induced damage, strenuous effort to remove filter cake and inherently reduces well productivity (Srivatsa & Ziaja, 2012). The experimental results proved that the usage of nano-silica had better fluid loss control as compared to standard polymer-based fluid loss additive because the nanoparticles acted as a better bridging agent to form an effective filter cake than the internal filter cake formed by the polymer additive as shown in Figure 2. (Long, et al., 2013).

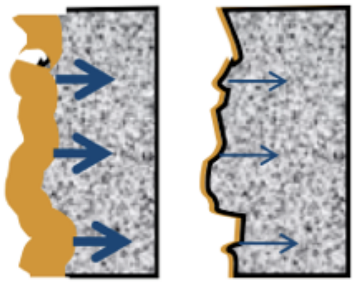

Figure 2: Thickness of Filter Cake, *(Riley, et al., 2012)*

So far, to solve the issue of borehole instability in unconventional reservoir, nano silica particles were used as plugging tools to stop the invasion of water into the small sized shale pores (10-30nm) (Holster, Stefano, Riley, & Young, 2012). The main issue faced when drilling in shale formations is water invasion, which causes shale swelling. The pressure penetration cannot be prevented with standard filtration additives, because shale pores are extremely small (approximately 0.01 micron) and shale permeability is extremely low (typically 0.01 microdarcy or less); therefore, a filter cake does not develop on shales as commonly used drilling additives such as barite and bentonite have larger particles in the range of 100-10,000nm (Russel, Russel, & Keith, 2009).

In experiments as depicted in Figure 3, where the nano-silica particles were used on Atoka shale; as the concentration of nano-silica was increased from 5% to 29%wt, an increase in plugging properties was observed this reducing permeability of the shale (Riley, et al., 2012). Aside from that, nanoparticles varying from 7-15nm with 10%wt concentration were shown to be effective in reducing shale permeability; hence, reducing interaction between water based mud and Atoka shale (Chai, Chenevert, Sharma, & Friedheim, 2012).

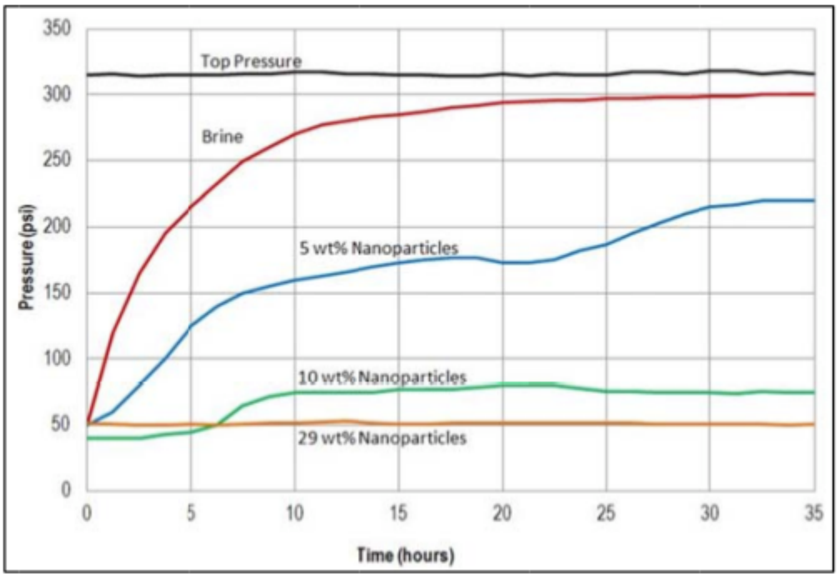

Figure 3: Plugging Effect with Different Nano-silica Concentrations. (Riley, et al., 2012)

CHAPTER 3

3.0 METHODOLOGY

3.1 Flowchart

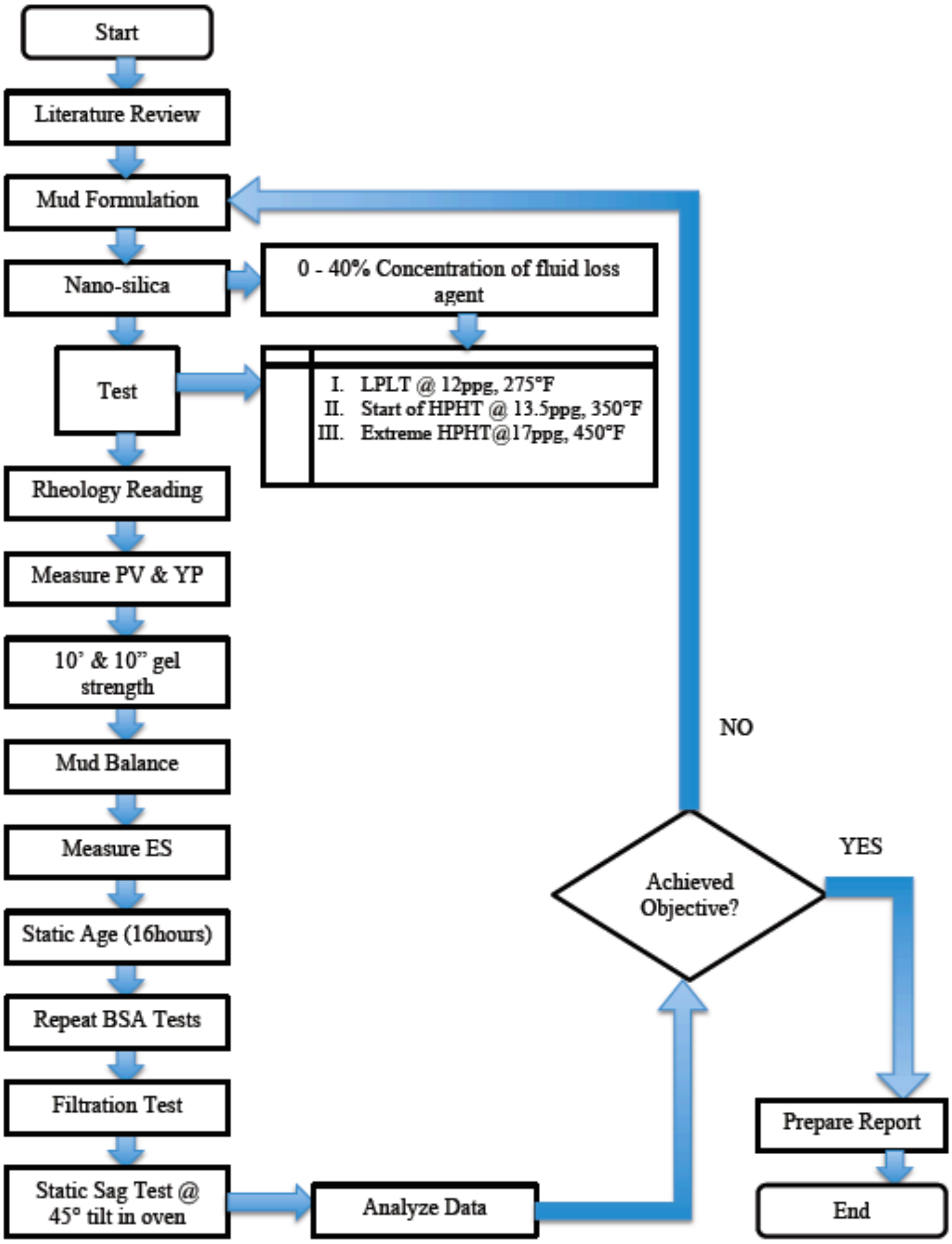

Figure 4: Flowchart of FYP

3.1.1 Flowchart Breakdown

The constituents below explain Figure 4 in detail.

Step 1: Start

Project begins.

Step 2: Literature Review

Journals, articles, books and websites are reviewed and compared to gain understanding and knowledge as depicted in Figure 4, on the subject of:

- Synthetic based muds
- Methodology of mud formulation
- Methodology of tests carried out on drilling fluids
- Nano-particles and nano-technology

Step 3: Mud Formulation

The mud is designed for three wellbore conditions: LPLT, starting point of HPHT conditions and extreme HPHT conditions. The mud formulations were obtained from a service company in the oil and gas industry. They have a joint venture with us where the chemicals are provided for us to be able to carry out the research, under their guidance and advise. The mud formulation will change slightly as nano-silica is added in varying concentrations, as depicted in Figure 4. The formulations are listed in Table 2 – Table 10.

Step 4: Determination of Nano-silica concentration

The nano-silica concentration was decided based on a limitation that the percentage of nano-silica within the mud should not exceed 0.5% of entire mud weight for economic purposes. The nano-silica was sent for characterisation at Block 17, UTP for nano-particle characterisation under the Scanning Electron Microscope (SEM).

Step 5 - 11: Testing the mud at different conditions

The mud will be tested at three conditions:

- Lower temperature conditions at 275°F

- Starting point of High Pressure High Temperature (HPHT) conditions of at 350°F
- Extreme HPHT conditions of at 450°F
- Nano-silica (10-20nm) will be added into these formulations as a fluid loss agent of 0 - 40%. The percentage of nano-silica added is the percentage of conventional fluid loss agent replaced. The tests carrried out can be divided into before static aging (BSA) and after static aging(ASA).

I. Before Static Aging Tests
  - Rheology Tests
  - Gel strength measurement
  - Plastic Viscosity and Yield Point measurement
  - Mud Balance Test

II. After Static Aging Tests
  - Rheology Test
  - Gel strength measurement
  - Plastic Viscosity and Yield Point measurement
  - Mud Balance Test
  - Sag Test
  - Filtration Test

*Note: All tests are explained in detail in procedures.

Step 12: Data Analysis

Data is then analyzed using the results obtained from the tests as depicted in Figure 4. The data will be tabulated in a manner shown in Chapter 3.7: Data Analysis.

Once the objective of the experiment is achieved, the report will be written and the project ends. If the objectives are not achieved, the loop is repeated from beginning from Step 3: Mud Formulation to investigate the cause of failure. The objectives are:

- To investigate effect of nano-silica on density of mud
- To obtain stable rheology at HPHT conditions
- To reduce fluid loss and obtain thin mudcake

3.2 Gantt Chart

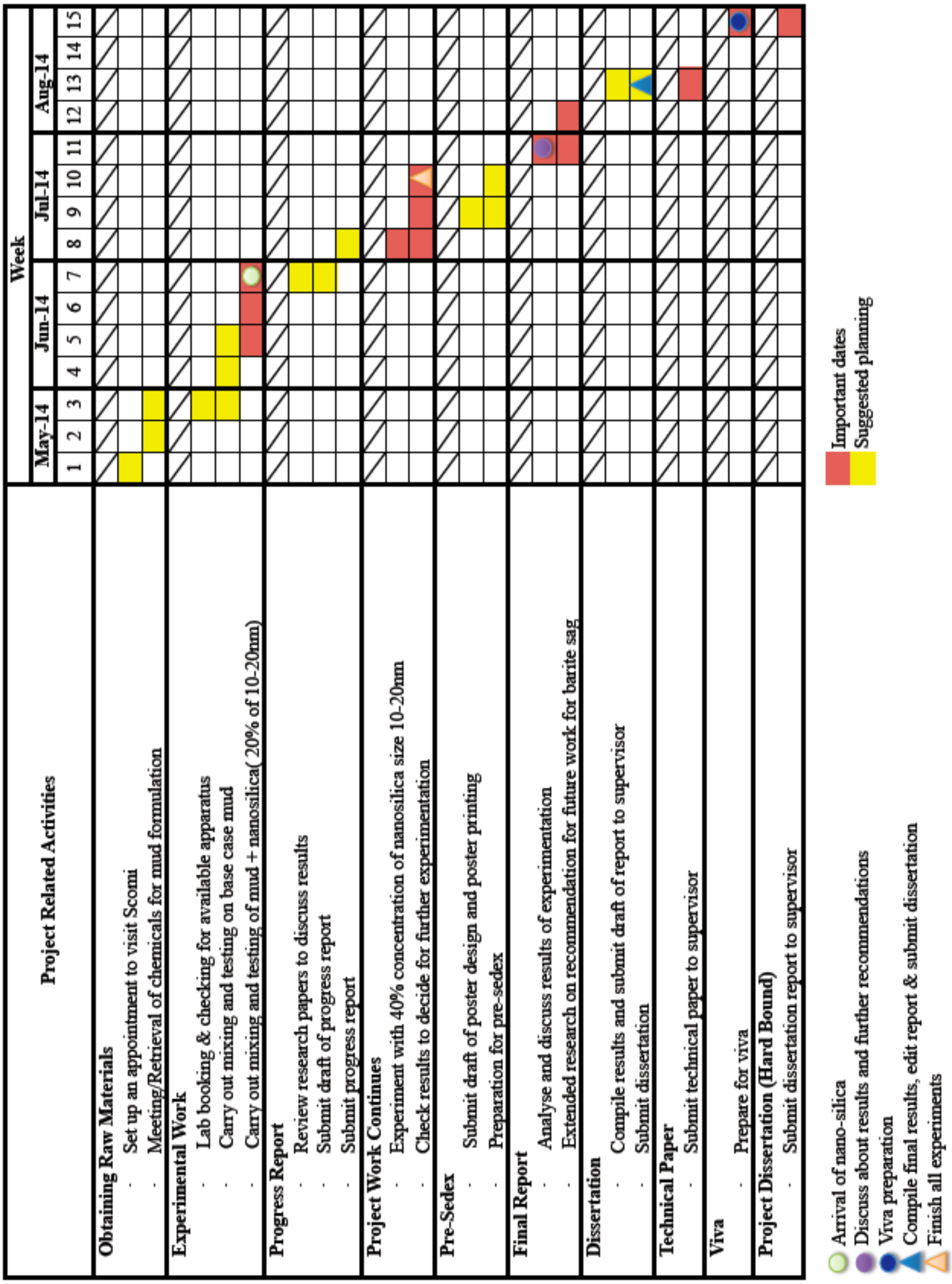

Figure 5: Gantt Chart

3.3 Mud Formulation

I. <u>Base Case</u>

Table 2: Formulation for 275°F @ 12ppg

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	-	-	160.08	ppb
Primary Emulsifier	1	2	3	ppb
Secondary Emulsifier	2	2	6	ppb
Viscosifier (premium organophilic clay)	3	5	3.75	ppb
Fluid Loss Agent	4	2	4	ppb
Lime	5	2	10	ppb
Drill Water	6	15	51.97	ppb
Calcium Chloride, 94% powder			25.06	ppb
Barite, 4.39SG	7	5	217.5	ppb
Drill Solids (Rev Dust)	8	5	20	ppb

Table 3: Formulation for 350°F @ 13.5ppg

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	143.86	ppb
Primary Emulsifier	2		13.8	ppb
Secondary Emulsifier	3		1.0	ppb
Viscosifier (premium organophilic clay)	4	2	2.5	ppb
Others	5	2	1.3	ppb
Fluid Loss Agent	6	2	9.9	ppb
Lime	7	2	11.3	ppb
Drill Water	8	15	46.71	ppb
Calcium Chloride, 95% powder			16.5	ppb
Barite, 4.39SG	9	2	297.8	ppb
Drill Solids (Rev Dust)	10	2	20.00	ppb

Table 4: Formulation for 450°F @ 17ppg

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	122.5	ppb
Primary Emulsifier	2		15.6	ppb
Secondary Emulsifier	3		1.9	ppb
Viscosifier (premium organophilic clay)	4	2	0.1	ppb
Others	5	2	1.0	ppb
Fluid Loss Agent	6	2	1.5	ppb
Lime	7	2	18.5	ppb
Drill Water	8	15	39.8	ppb
Calcium Chloride, 95% powder			9.4	ppb
Barite, 4.2SG	9	2	482.4	ppb
Drill Solids (Rev Dust)	10	2	19.5	ppb

II. Base Case + 20% nanosilica concentration (10-20nm)

Table 5: Formulation for 275°F@ 12ppg (20% nano-silica)

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	160.15	bbl
Primary Emulsifier	2		3	ppb
Secondary Emulsifier	3		6	ppb
Viscosifier (premium organophilic clay)	4	2	3.75	ppb
Fluid Loss Agent	5	2	1.06	ppb
20% nanosilica (10-20nm)	6	2	0.8	ppb
Lime	7	2	10	ppb
Drill Water	8	15	52	bbl
Calcium Chloride, 95% powder			25.06	ppb
Barite, 4.39SG	9	2	216.98	ppb
Drill Solids (Rev Dust)	10	2	20	ppb

Table 6: Formulation for 350°F @ 13.5ppg (20% nano-silica)

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	144.59	bbl
Primary Emulsifier	2		13.8	ppb
Secondary Emulsifier	3		1	ppb
Viscosifier (premium organophilic clay)	4	2	2.50	ppb
Others	5	2	1.3	ppb
Fluid Loss Agent	6	2	7.92	ppb
20% nanosilica (10-20nm)	7	2	1.98	ppb
Lime	8	2	11.3	ppb
Drill Water	9	15	46.95	bbl
Calcium Chloride, 95% powder			16.5	ppb
Barite, 4.39SG	10	2	296.81	ppb
Drill Solids (Rev Dust)	11	2	20	ppb

Table 7: Formulation 450°F @ 17ppg (20% nano-silica)

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	122.57	bbl
Primary Emulsifier	2		15.6	ppb
Secondary Emulsifier	3		1.9	ppb
Viscosifier (premium organophilic clay)	4	2	0.1	ppb
Others	5	2	1.0	ppb
Fluid Loss Agent	6	2	1.2	ppb
20% nanosilica (10-20nm)	7	2	0.3	ppb
Lime	8	2	18.5	ppb
Drill Water	9	15	39.8	bbl
Calcium Chloride, 95% powder			9.4	ppb
Barite, 4.39SG	10	2	482.23	ppb
Drill Solids (Rev Dust)	11	2	19.5	ppb

III. Base Case + 40% Nano Concentration

Table 8: Formulation for 275°F @ 12ppg (40% nano-silica)

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	160.67	bbl
Primary Emulsifier	2		3	ppb
Secondary Emulsifier	3		6	ppb
Viscosifier (premium organophilic clay)	4	2	3.75	ppb
Fluid Loss Agent	5	2	2.4	ppb
40% nanosilica (10-20nm)	6	2	1.6	ppb
Lime	7	2	10	ppb
Drill Water	8	15	52.16	bbl
Calcium Chloride, 95% powder			25.06	ppb
Barite, 4.39SG	9	2	216.69	ppb
Drill Solids (Rev Dust)	10	2	20	ppb

Table 9: Formulation for 350°F @ 13.5ppg (40% nano-silica)

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	145.32	bbl
Primary Emulsifier	2		13.8	ppb
Secondary Emulsifier	3		1	ppb
Viscosifier (premium organophilic clay)	4	2	2.50	ppb
Others	5	2	1.3	ppb
Fluid Loss Agent	6	2	5.94	ppb
40% nanosilica (10-20nm)	7	2	3.96	ppb
Lime	8	2	11.3	ppb
Drill Water	9	15	47.18	bbl
Calcium Chloride, 95% powder			16.5	ppb
Barite, 4.39SG	10	2	295.83	ppb
Drill Solids (Rev Dust)	11	2	20	ppb

Table 10: Formulation for 450°F @ 17ppg (40% nano-silica)

Mud Materials	Mixing Order	Time (minutes)	T1	
Base Oil	1	4	122.69	bbl
Primary Emulsifier	2		15.6	ppb
Secondary Emulsifier	3		1.9	ppb
Viscosifier (premium organophilic clay)	4	2	0.1	ppb
Others	5	2	1.0	ppb
Fluid Loss Agent	6	2	0.9	ppb
40% nanosilica (10-20nm)	7	2	0.6	ppb
Lime	8	2	18.5	ppb
Drill Water	9	15	39.83	bbl
Calcium Chloride, 95% powder			9.4	ppb
Barite, 4.39SG	10	2	482.07	ppb
Drill Solids (Rev Dust)	11	2	19.5	ppb

*Certain chemicals are not stated in the Tables 3 to 10 due to confidentiality.

Function of chemicals:

- Base oil: Base fluid of the drilling fluid
- Emulsifiers: Creates an emulsion of two insoluble fluids (eg, water and oil)
- Viscosifier: To increase viscosity of drilling fluids
- Fluid Loss Agent: To prevent fluid loss from mud
- Lime: Increases mud viscosity by flocculation
- Drill Water:Also known as brine
- Calcium Chloride: To prevent formation swelling
- Barite: Weighing agent to increase weight of mud
- Drill solids: Acts as contamination to the mud to evaluate stability of the system

3.4 Nano-silica Characterization

Results from the Scanning Electron Microscope (SEM)

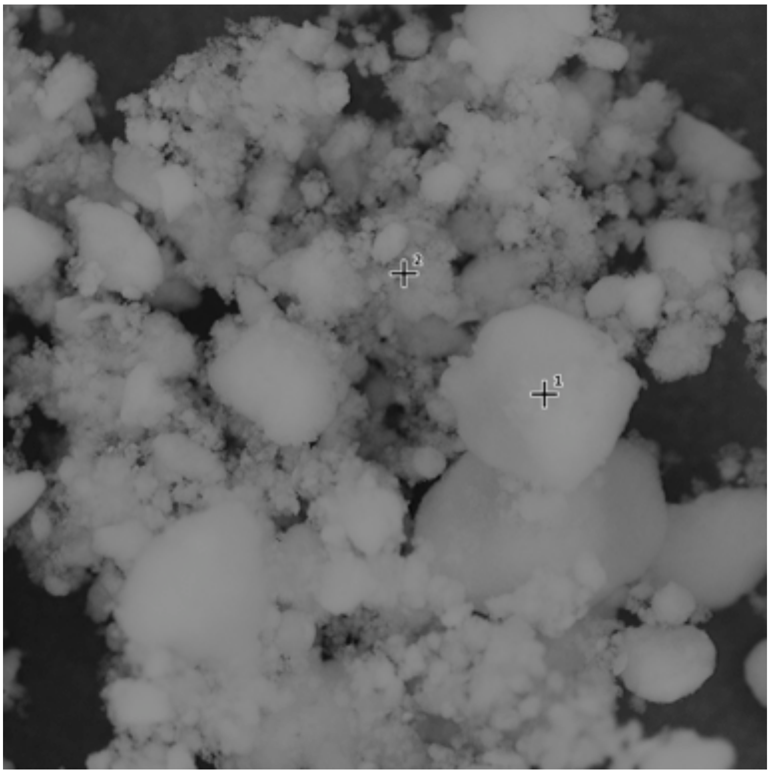

Figure 6: Nano-silica Image under SEM

- Spot 1:

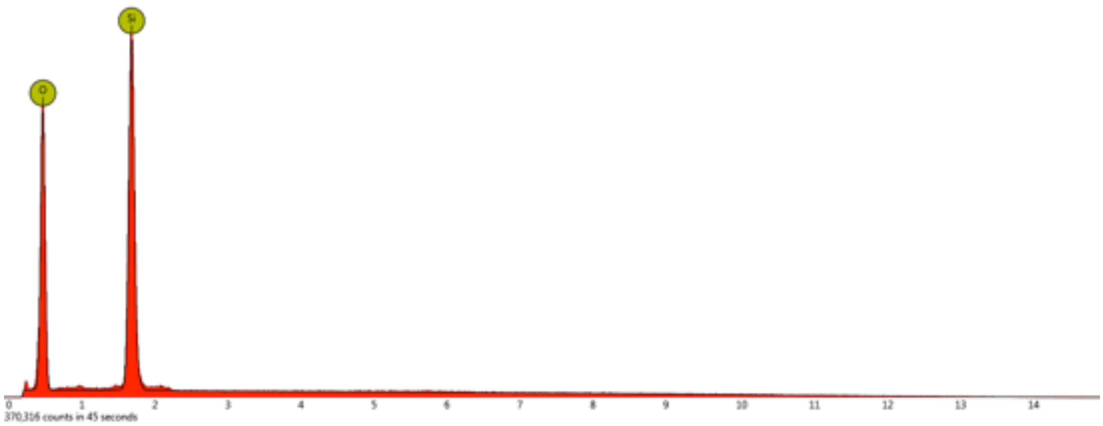

Figure 7: Spectrum of Nano-silica at Spot 1

Table 11: Quantification of Nano-silica

Element Number	Element Symbol	Element Name	Confidence	Concentration	Error
14	Si	Silicon	100.0	23.9	0.3
8	O	Oxygen	100.0	76.1	0.4

- Spot 2

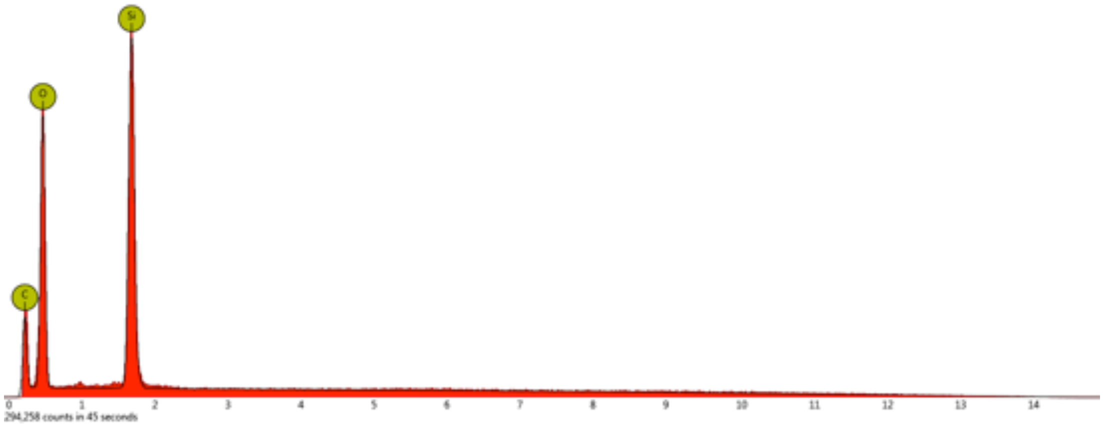

Figure 8: Spectrum of Nano-silica at Spot 2

Table 12: Quantification of Nano-silica at Spot 2

Element Number	Element Symbol	Element Name	Confidence	Concentration	Error
14	Si	Silicon	100.0	20.9	0.4
8	O	Oxygen	100.0	73.5	0.6
6	C	Carbon	100.0	5.6	1.2

Figure 6 shows analyses of selected point locations on the nano-silica sample. The scanning electron microscope (SEM) uses a focused beam of high-energy electrons to generate a variety of signals at the surface of solid specimens. The signals that derive from electron-sample interactions reveal information about the sample (nano-silica) including external morphology (texture) as depicted in Figure 6, chemical composition (Table 11, 12), and illustrating contrasts in composition in multiphase samples (i.e. for rapid phase discrimination) as depicted in Figure 7 and 8.

3.5 Parameter Range

Table 13: Parameter Range

Temperature, °F	275	350	450
Mud Weight, ppg	12	13.5	17

The other manipulated variables are nano-particle concentration and size:

- Nano-particle: nano-silica
- Nano-particle size:
    - 10-20nm
- Nano-particle concentration: 0 - 40% of fluid loss agent

3.6 EXPERIMENT METHODOLOGY

3.6.1 Proposed Experimental Procedure

Mud Rheology

Fann 35 Viscometer can determine the mud rheology. For the procedure, API 13B is suitable for field-testing water based muds. The six readings will be taken at 120°F.

Figure 9: Fann 35 Viscometer

Procedure of Checking Mud Rheology

1. The drilling mud is filled into a measuring cup. The sleeve is then immersed into the cup until the sleeve's holes are covered mud.
2. The VG meter is switched on at 600rpm.
3. The experiment is left till the drilling mud reaches 120°F.
4. The reading is taken at 600rpm, 300rpm, 200rpm, 100rpm, 6rpm and 3rpm.
5. The plastic viscosity and yield point is calculated.

Measuring Gel Strength

1. The sample is stirred thoroughly at 600rpm.
2. The gearshift knob is set to 3rpm position, and then the motor is turned off.
3. After the desired wait time, the motor is turned back on at low speed.
4. The reading is taken when the gel breaks as noted by a peak dial reading. The gel unit strengths are lb/100ft2.

Measuring Plastic Viscosity and Yield Point

From the rheological properties obtained from 600rpm and 300rpm, the readings can be converted into plastic viscosity (PV) and yield point(YP).

1. Plastic Viscosity (PV), cp = Reading at 600 rpm- Reading at 300rpm
2. Yield Point (YP) lb/100ft2 = Reading at 300 rpm - PV

Sag Test

1. Initial density is measured and the mud is placed in an aging cell.
2. The mud is static aged over a certain period of time at the desired bottom hole pressure at a 45° tilt.
3. The mud density difference before and after the static aging is measured and sag index is calculated.

Calculation:

The specific gravity of the upper part (D1) and bottom part (D3) of mud is weighed and sag index is calculated as follows:

Method 1: GRTC

Equation 2: Sag Factor

$$Sag\ factor = \frac{SG\ bottom}{SG\ top\ + SG\ bottom}$$

SG = specific gravity

*Note: Free fluid is combined with top section of mud

Figure 11: Sag Test

Figure 10: Procedure of Sag Test

Filtration Test

Aim: To measure the filtration rate and fluid loss of mud.

1. The API cell and the filter screen are assembled.
2. The filter paper and O-ring are inserted into the cell assembly and the cell assembly is tightened.

3. The drilling mud is poured until it fills ¾ from the top of the cell.
4. The top of the cell is closed tightly to prevent pressure leakage.
5. A graduated cylinder is placed below the cell's tube.
6. The red button is pulled out and the valve is opened.
7. 100 psi of pressure is applied for 30 minutes.
8. After 30 minutes, the filtrate collected in the cylinder is measured.
9. The pressure valve is closed and the pressure is released. The cell is taken apart.
10. If there is need to measure mud cake thickness, the cake is formed on the filter paper.

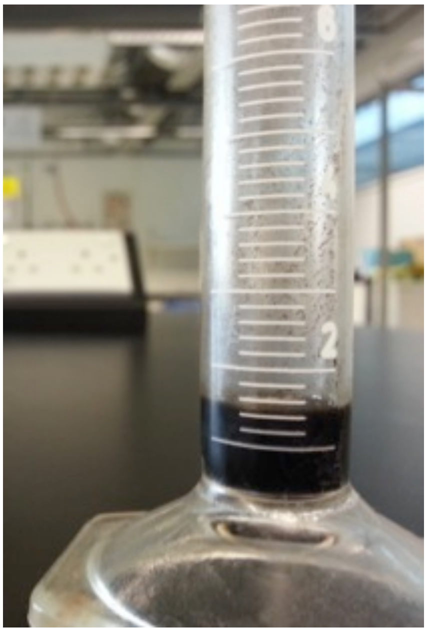

Figure 12: Total Filtrate Loss

3.6.2 Tools and Equipment

- Fann 35 viscometer
- Stopwatch
- Mud cup
- Thermometer
- Aging cell
- Retort cup
- Weighting scale
- Filtration cell
- Filter paper
- Measuring cylinder

3.7 Data Analysis

Table 14: Rheology Properties Results

Mud Weight, ppg	**12**	**13.5**	**17**
Oven Temperature,°F	275	350	450
Plastic Viscosity, cP			
Yield Point, lb/100 sqft			
10' gel strength, lb/100ft^2			
10" gel strength, lb/100ft^2			
600 rpm dial reading			
300 rpm dial reading			
200 rpm dial reading			
100 rpm dial reading			
6 rpm dial reading			
3 rpm dial reading			
HTHP (300F), ml			
Filter Cake, 32inch			
ES, volt			
Sag Factor			

3.7.1 Data Analysis Breakdown

- *Oven Temperature*: Temperature at three conditions of LPLT (275°F), starting point of HPHT (350°F), and extreme HPHT (450°F).
- *Plastic viscosity* is the resistance to fluid flow, which functions to suspend cuttings via high viscosity. Therefore, the PV must be sufficient enough to transport cuttings effectively.
- *Yield point* functions as the ability of a mud to circulate cuttings out of the annulus. Therefore, the YP must be high enough to suspend cuttings as the travel up the annulus.
- *10' and 10" gel strength*: Gel strength functions to suspend drill solid and weighing materials when circulation stops. The function of the 10minutes reading is to investigate the mud's ability to form gel during an extended static period.
- *600, 300, 200, 100, 6, 3 rpm*: Different viscosities measures at different rotational speeds to obtain PV, YP and gel strength.

- *HPHT @ 300°F*: Fluid expelled at a certain temperature and pressure in 30 minutes intervals.
- *Filter Cake*: Filter cake should be in the range of 1" – 2/32".
- *Electrical Stability (ES)*:To monitor fluid's emulsion and oil wetting stability.
- *Oil Water Ratio (OWR)*: To indicate the level and amount of water and oil extracted
- *Sag Factor*: Sag factor of 0.5 and below indicates no weighing agent sedimentation.

CHAPTER 4

4.0 RESULTS & DISCUSSION

4.1 Criterion After Static Aging Results

Table 15: Criterion Results for SBM of 275°F @ 12ppg

Mud Type	Non-Aqueous Fluid (NAF)
Static Age Temperature (°F)	275
Mud Density (ppg)	12
Plastic Viscosity, cP	< 35
Yield Point, lb/100 sqft	15-25
Initial Gel Strength, lb/100 sqft	6-10
6 rpm Fann reading	8-12
HPHT Fluid Loss, cc/30min	$\leq 5(275°\text{F}/500\text{psi})$
Free Water in Filtrate	-
HPHT Filter Cake, 32^{nd} inch	< 2
Electrical Stability, volts	> 500
Water Phase Salinity (% CaCl2 by weight)	24%-27%
OWR	75/25
Excess Lime, ppb	2-3

Table 16: Criterion Results for SBM of 350°F @ 13.5ppg

Mud Type	Non-Aqueous Fluid (NAF)
Static Age Temperature (°F)	350
Mud Density (ppg)	13.5
Plastic Viscosity, cP	< 45
Yield Point, lb/100 sqft	15-30
Initial Gel Strength, lb/100 sqft	6-12
6 rpm Fann reading	8-12
HPHT Fluid Loss, cc/30min	$\leq 4(275°\mathrm{F}/500\mathrm{psi})$
Free Water in Filtrate	-
HPHT Filter Cake, 32nd inch	≤ 2
Electrical Stability, volts	> 500
Water Phase Salinity (% CaCl2 by weight)	24%-27%
OWR	80/20
Excess Lime, ppb	2-3
Sag Factor	< 0.53

Table 17: Criterion Results for SBM of 450°F @ 17ppg

Mud Type	Non-Aqueous Fluid (NAF)
Static Age Temperature (°F)	450
Mud Density (ppg)	17
Plastic Viscosity, cP	< 65
Yield Point, lb/100 sqft	15-30
Initial Gel Strength, lb/100 sqft	6-12
6 rpm Fann reading	8-12
HPHT Fluid Loss, cc/30min	$\leq 4(275°F/500psi)$
Free Water in Filtrate	-
HPHT Filter Cake, 32^{nd} inch	≤ 2
Electrical Stability, volts	> 500
Water Phase Salinity (% CaCl2 by weight)	24%-27%
OWR	85/15
Excess Lime, ppb	2-3
Sag Factor	< 0.53

4.2 Obtained Experimental Results

Condition: Static Aging in Oven

Nano-particle size: 10-20nm

Table 18: Rheology Results of Base Case vs Nano Mud at 275°F @ 12ppg

Initial properties			
	Base Case Mud	**Nano Mud@20%**	**Nano Mud@40%**
Rheology at	120F	120F	120F
600 rpm dial reading	50	50	53
300 rpm dial reading	29	29	32
200 rpm dial reading	21	21	25
100 rpm dial reading	13	13	16
6 rpm dial reading	9	7	7
3 rpm dial reading	4	5	6
Plastic viscosity, cP	21	21	19
Yield point, lb/100ft^2	8	8	13
10' gel strength, lb/100ft^2	14	7	9
10" gel strength, lb/100ft^2	16	12	13
ES, volt	651	613	624
Mud Weight (MW)	12	12	12
Static Properties @ 275°F, 16 hours			
600 rpm dial reading	51	53	50
300 rpm dial reading	29	30	31
200 rpm dial reading	21	22	23
100 rpm dial reading	14	15	15
6 rpm dial reading	6	7	6
3 rpm dial reading	5	6	5
Plastic viscosity, cP	22	23	19
Yield point, lb/100ft^2	8	7	12
10' gel strength, lb/100ft^2	9	8	8
10" gel strength, lb/100ft^2	11	12	11
ES, volt	658	736	630
Mud Weight (MW)	11.95	11.95	12
HTHP (300F),ml	6	5.2	4.8
Filter Cake, 32inch	4 / 32	2.5 / 32	2 / 32
Sag factor	0.616	0.618	0.563

Table 19: Rheology Results of Base Case vs Nano Mud at 350°F @ 13.5ppg

Initial properties			
	Base Case Mud	**Nano Mud@20%**	**Nano Mud@40%**
Rheology at:	120F	120F	120F
600 rpm dial reading	96	100	98
300 rpm dial reading	58	60	59
200 rpm dial reading	44	45	45
100 rpm dial reading	29	29	29
6 rpm dial reading	12	12	12
3 rpm dial reading	11	11	10
Plastic viscosity, cP	38	40	39
Yield point, lb/100ft^2	20	20	20
10' gel strength, lb/100ft^2	18	12	14
10" gel strength, lb/100ft^2	37	44	40
ES, volt	757	744	787
Mud Weight (MW)	13.5	13.5	13.5
Static Properties @ 350°F, 16 hours			
600 rpm dial reading	143	112	103
300 rpm dial reading	84	66	60
200 rpm dial reading	62	49	44
100 rpm dial reading	38	30	28
6 rpm dial reading	11	9	8
3 rpm dial reading	8	6	7
Plastic viscosity, cP	59	46	43
Yield point, lb/100ft^2	25	20	16
10' gel strength, lb/100ft^2	12	8	10
10" gel strength, lb/100ft^2	46	38	33
ES, volt	1113	1197	859
Mud Weight (MW)	14.2	13.5	13.5
HTHP (300F), ml	5.6	4.8	4
Filter Cake, 32inch	3.5 / 32	2 / 32	1.5/32 – 2/32
Sag factor	0.629	0.625	0.565

Table 20: Rheology Results of Base Case vs Nano Mud at 450°F @ 17ppg

Initial properties			
	Base Case Mud	**Nano Mud@20%**	**Nano Mud@40%**
Rheology at	120F	120F	120F
600 rpm dial reading	122	105	117
300 rpm dial reading	68	60	68
200 rpm dial reading	50	45	51
100 rpm dial reading	31	28	32
6 rpm dial reading	9	10	12
3 rpm dial reading	8	8	10
Plastic viscosity, cP	54	45	49
Yield point, $lb/100ft^2$	14	25	21
10' gel strength, $lb/100ft^2$	11	26	16
10" gel strength, $lb/100ft^2$	22	28	33
ES, volt	932	1093	1298
Mud Weight (MW)	17	17	17
Static Properties @ 450°F, 16 hours			
600 rpm dial reading	243	192	160
300 rpm dial reading	164	116	99
200 rpm dial reading	129	88	76
100 rpm dial reading	84	56	50
6 rpm dial reading	34	19	25
3 rpm dial reading	39	18	23
Plastic viscosity, cP	79	76	61
Yield point, $lb/100ft^2$	85	40	38
10' gel strength, $lb/100ft^2$	52	29	32
10" gel strength, $lb/100ft^2$	75	39	60
ES, volt	924	947	1018
Mud Weight (MW)	16.95	17.05	17.15
HTHP (300F), ml	5.2	4.6	4.4
Filter Cake, 32inch	3/32	2.5/32	1.5/32 – 2/32
Sag factor	0.503	0.508	0.498

4.3 Discussion of Results

*BSA=Before Static Aging

*ASA= After Static Aging

4.3.1 Rheology Properties

i. Dial Reading

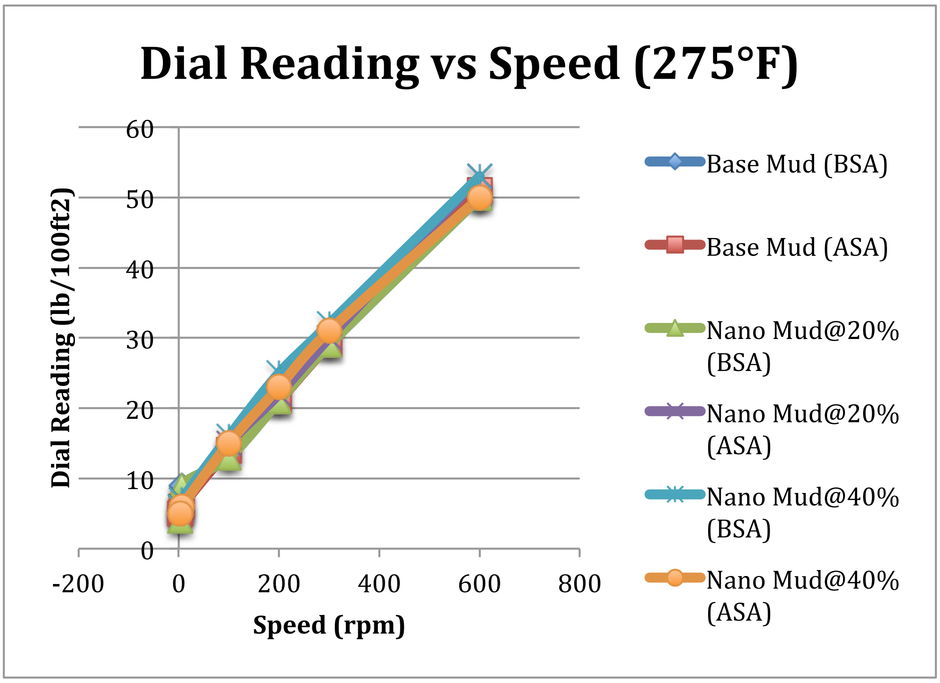

Figure 13: Dial Reading vs Speed @ 12ppg

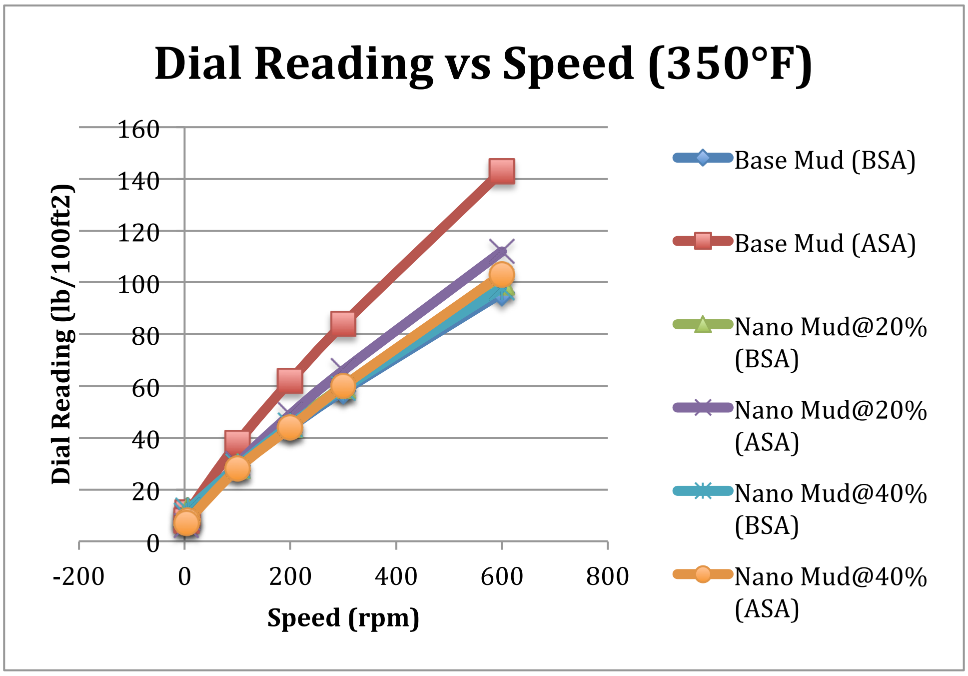

Figure 14: Dial Reading vs Speed @ 13.5ppg

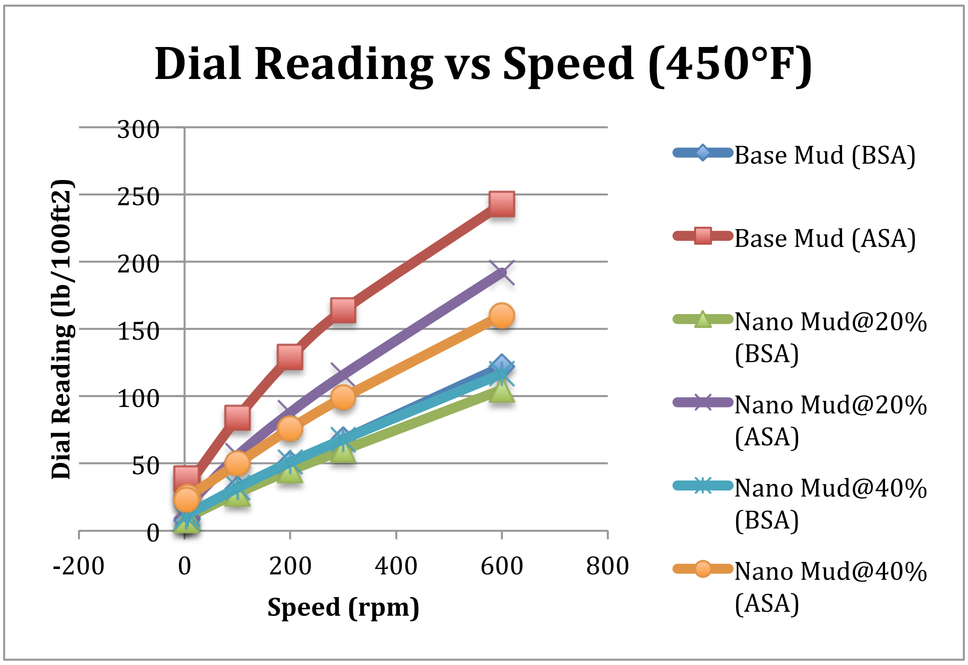

Figure 15: Dial Reading vs Speed @ 17ppg

The graphs above illustrate the change in dial reading at different speeds after static heating. The speeds are:

- 600 rpm
- 300 rpm
- 200 rpm
- 100 rpm
- 6 rpm
- 3 rpm

The 6-speed viscometers consisting of the above speeds, as shown above, are used on the oilfield to permit rheology of the mud to be measured at a range of shear rates in the mud circulation system. Comparing the results of both base case mud and nano enhanced mud, it appears that with the usage of 10-20nm sized nano-silica at 20% and 40% concentration in Figure 13, 14 and 15, the rheology properties are more stable than base case mud without any nano-silica additive. With the usage of nano-silica, the values of the dial readings after static heating are closer to the values of the mud before static heating, thereby indicating a stable rheology over a range of temperature conditions. This proves that nano-silica can act as a rheology modifier due to its high thermal stability (Zhang, et al., 2012) with approximately 1700°C melting point, which is higher than normal additives. Constant rheology can reduce downhole surge pressures and equivalent circulating density (ECD), thereby minimizing frequency and severity of lost circulation incidents (Rojas, et al., 2007). The dial readings indicate pump pressure/strength required to achieve the pre-determined speed(rpm). Therefore, the readings are always higher after exposure to high temperatures because of thermal degradation, gelation, degradation of weighting material, breakdown of polymeric additives (viscosifiers, surfactants, and fluid loss additives) caused by HPHT conditions on the properties of the mud. This same principle applies to all other readings.

ii. Plastic Viscosity

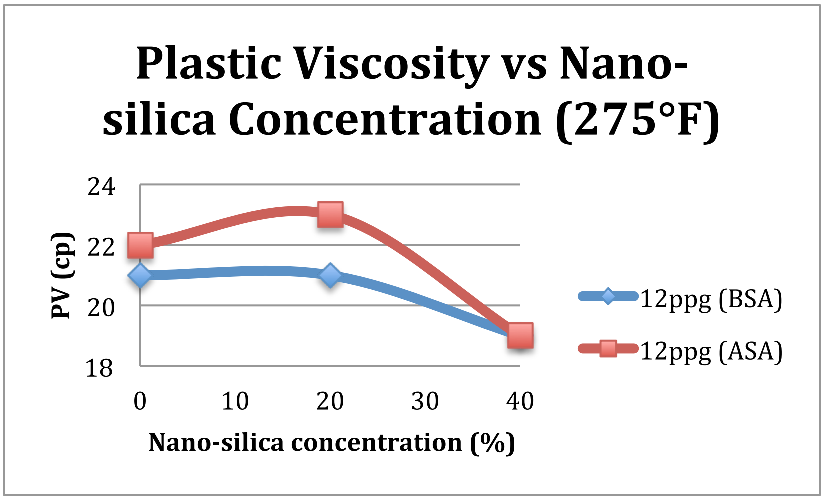

Figure 17: PV vs Nano-silica Concentration @ 12ppg

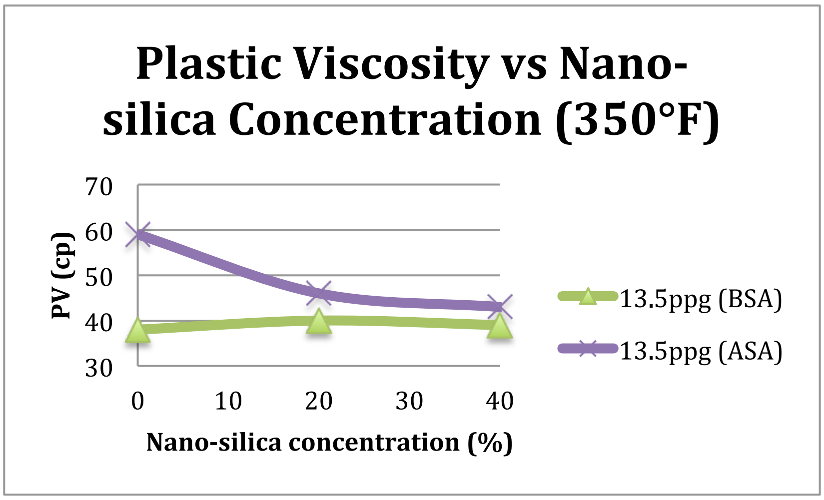

Figure 16: PV vs Nano-silica Concentration @ 13.5ppg

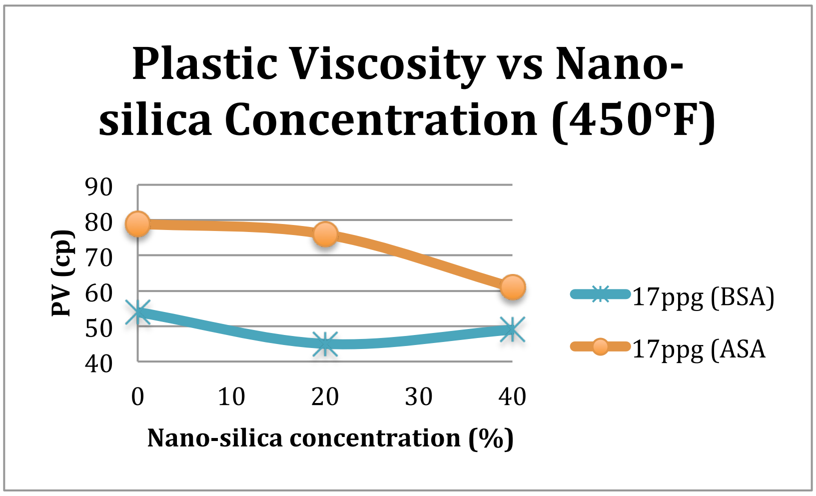

Figure 18: PV vs Nano-silica Concentration @ 17ppg

Figure 16, 17 and 18 shows the plot of plastic viscosity versus nano-silica concentrations for all 12ppg, 13.5ppg and 17ppg mud weight. From the figure, it can be concluded that as nano-silica concentration increases, the plastic viscosity becomes more stable as the readings showed little variation before and after static aging in the oven. As mentioned before, plastic viscosity is the resistance to fluid flow. An increase in solids content will increase the plastic viscosity of the drilling fluid. According to (Agharwal, Tran, Soong, Martello, & Gupta, 2011), when emulsion stabilized by a polymer surfactant was aged, it degraded severely, and oil and water phases separated and could not be emulsified again. However, using nano-silica, emulsion stability was maintained even when the mud was exposed to high temperatures. This can explain the stable values of plastic viscosity at higher concentration of nano-silica. When the sizes of nanoparticles are smaller than the wavelength of conduction electrons (100nm), the periodic boundary conditions become damaged, and therefore, magnetic, internal pressure, optical absorption, thermal resistance, chemical activity, catalysis, and melting point undergo massive changes as opposed to normal particles (Kong & Ohadi, 2010).

iii. Yield Point

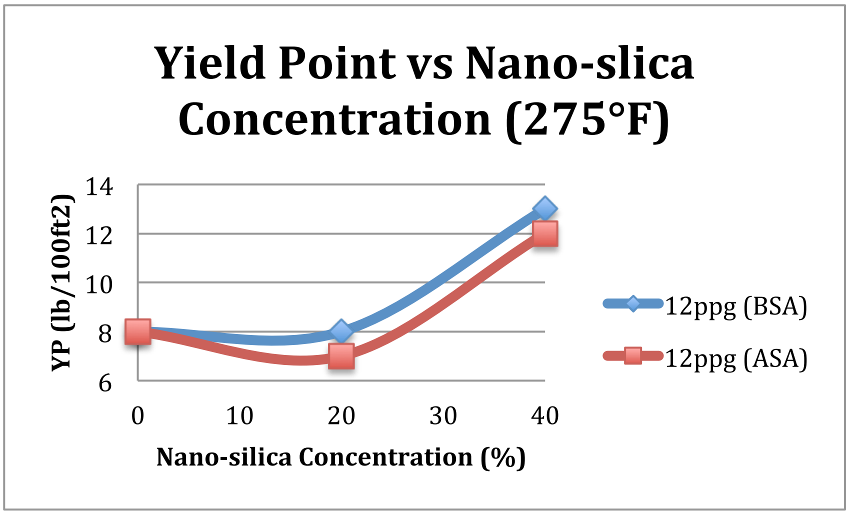

Figure 19: YP vs Nano-silica Concentration @ 12ppg

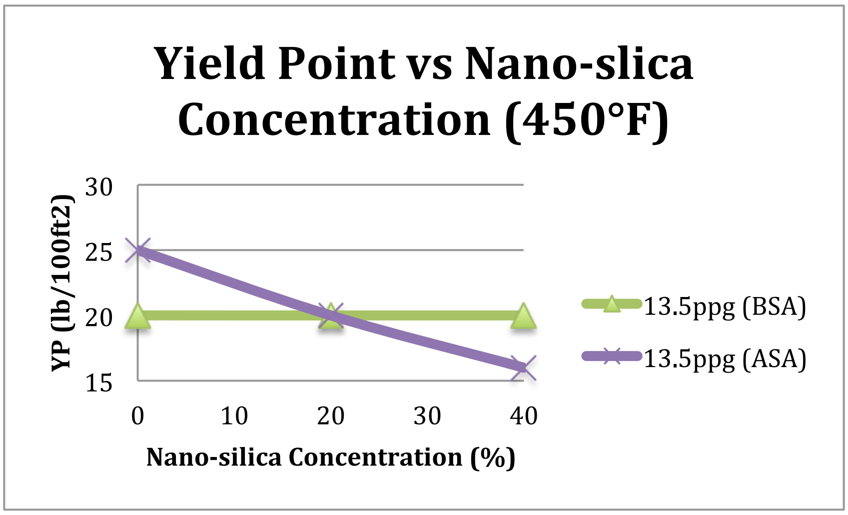

Figure 20: YP vs Nano-silica Concentration @ 13.5ppg

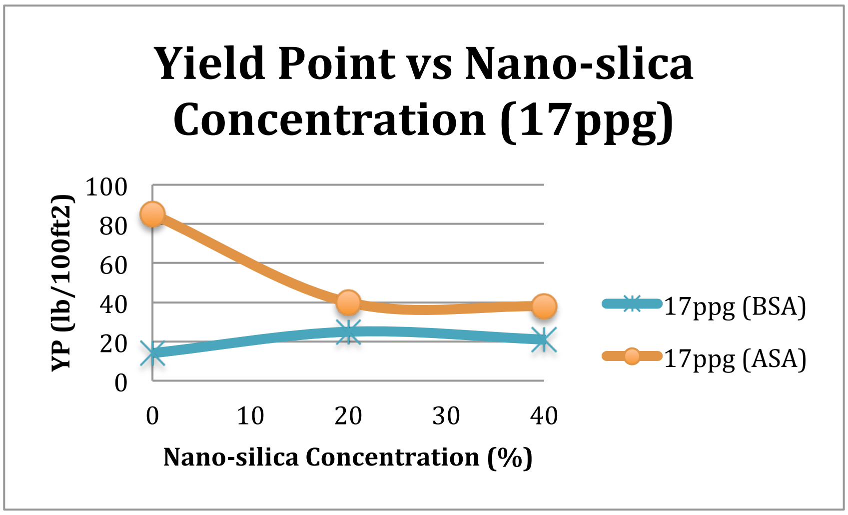

Figure 21: YP vs Nano-silica Concentration @ 17ppg

The acceptable ranges for Yield Point after static aging are shown below:

Table 21: Acceptable Yield Point Range at given Conditions

Conditions	Yield Point (lb/100ft2)
275°F, 12ppg	15 – 25
350°F, 13.5ppg	15 – 30
450°F, 17ppg	15 – 30

Referring to Figures 19, 20 and 21, the yield point of the mud is within the acceptable range at 40% concentration, except for a fluctuation in the 17ppg after static aging. As mentioned before, yield point is the ability of the mud to lift cuttings out of the wellbore.

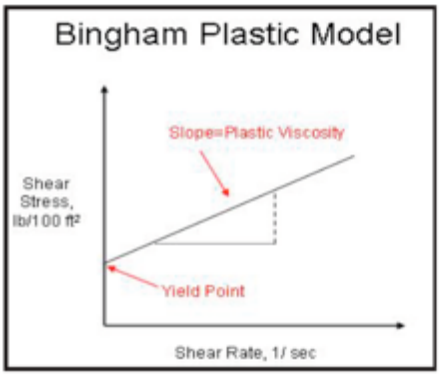

Figure 22: Bingham Plastic Model

Figure 22 above shows how plastic viscosity is related to yield point. Yield point can be derived as plastic viscosity at zero shear rate. According to (Agharwal, Tran, Soong, Martello, & Gupta, 2011), if the aged drilling fluid was again homogenized by high-speed stirring, an emulsion with fine droplets was obtained, which will increase in yield stress values to stabilize the emulsion. This can also explain the stable yield point and plastic viscosity values at higher concentration of nano-silica.

iv. Gel Strength

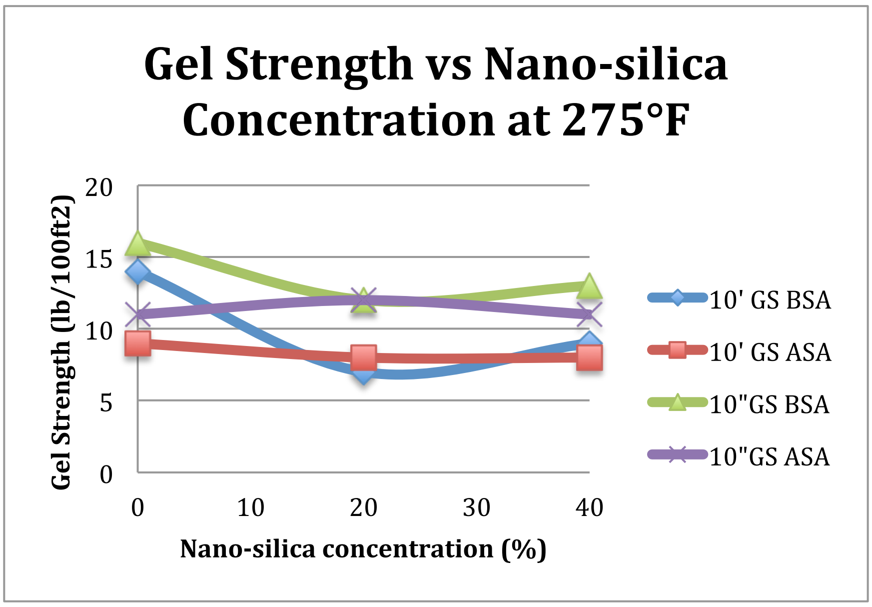

Figure 23: Gel Strength vs Nano-silica Concentration @ 12ppg

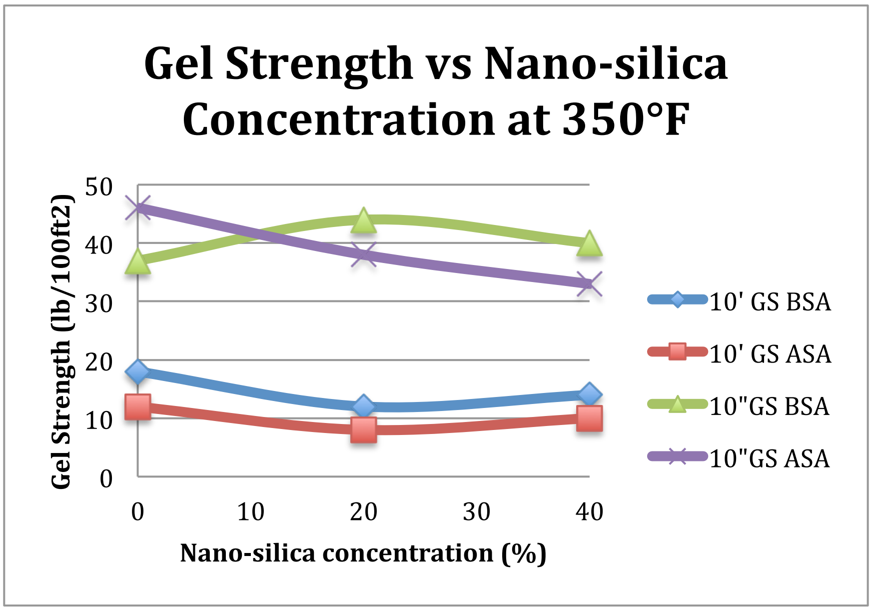

Figure 24: Gel Strength vs Nano-silica Concentration @ 13.5ppg

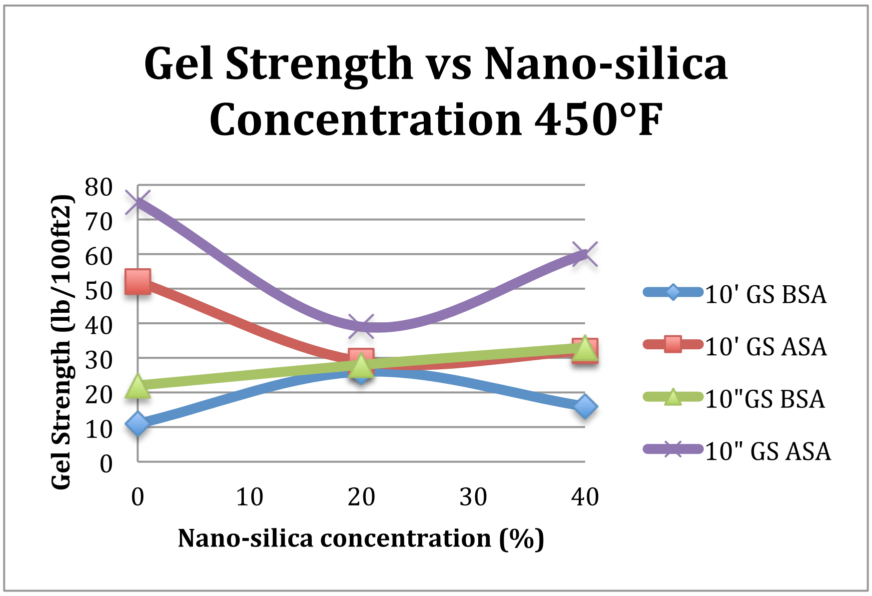

Figure 25: Gel Strength vs Nano-silica Concentration @ 13.5ppg

From Figure 23, 24 and 25, the gel strength of 10seconds (10') and 10 minutes (10") show less variation before and after static aging with the addition of nano-silica.

Table 22: Acceptable Range of Gel Strength

Conditions	Gel Strength (lb/100ft2)
275°F, 12ppg	6-10
350°F, 13.5ppg	6-12
450°F, 17ppg	6-12

Gel strength depicts the capability of the mud to suspend solids and weighting material when circulation ceases, and also to flow when force is applied. Generally, addition of nano-silica increases the gel strength of the mud. Drilling muds exhibiting high gel strength will create the need for high pump pressure to break the static condition the mud was in for an extended period of time. The reasons that may cause high gel strength in a mud is due to over treatment with organic gelling material or build up of fine solid particles in the mud. The gel strength of a mud needs to be within the operational limit as shown in Table 22 to avoid problems such as:

- **Cutting suspension disability**: gel strength lower than the operational range will cause cuttings to drop once the pumps are not working (no suspension), which can lead to pipe sticking, accumulation of cutting beds and hole pack off.
- **High break circulation pressure**: gel strength above the operational limit will require a huge amount of pressure to break the mud into circulation. This high pumping pressure can cause formation damage (break formation), which will result in mud loss and loss circulation.

v. Electrical Stability

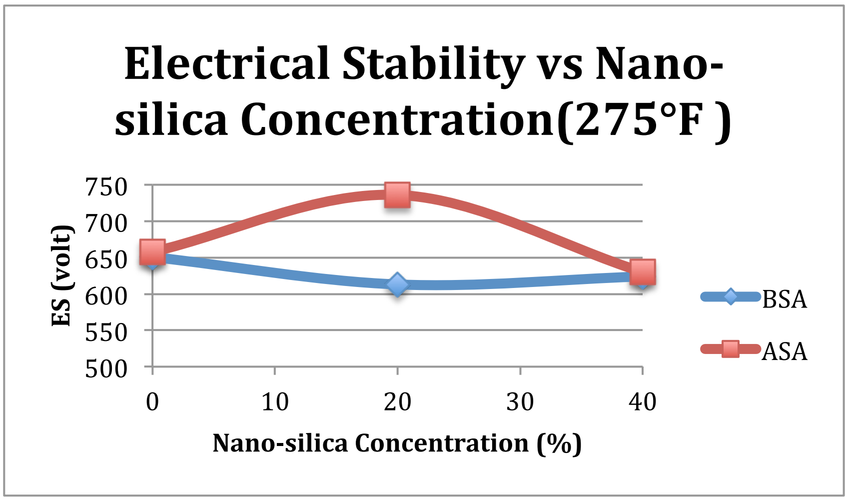

Figure 26: ES vs Nano-silica Concentration @ 12ppg

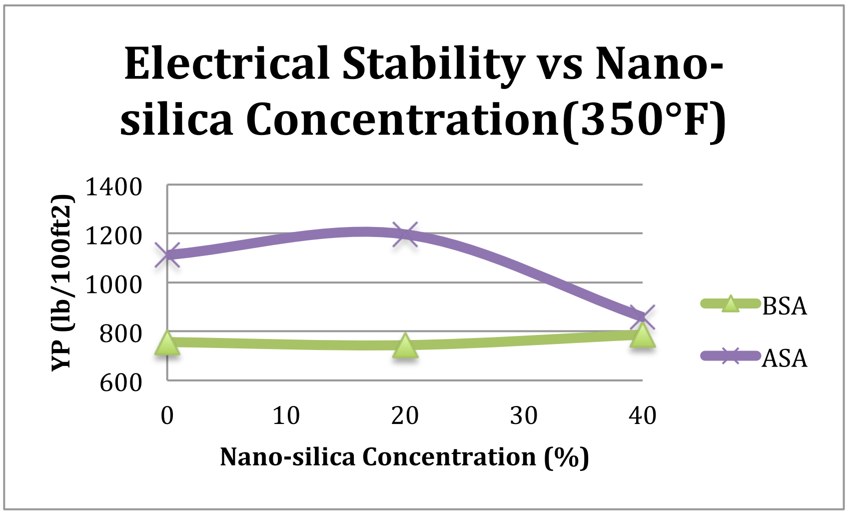

Figure 27: ES vs Nano-silica Concentration @ 13.5ppg

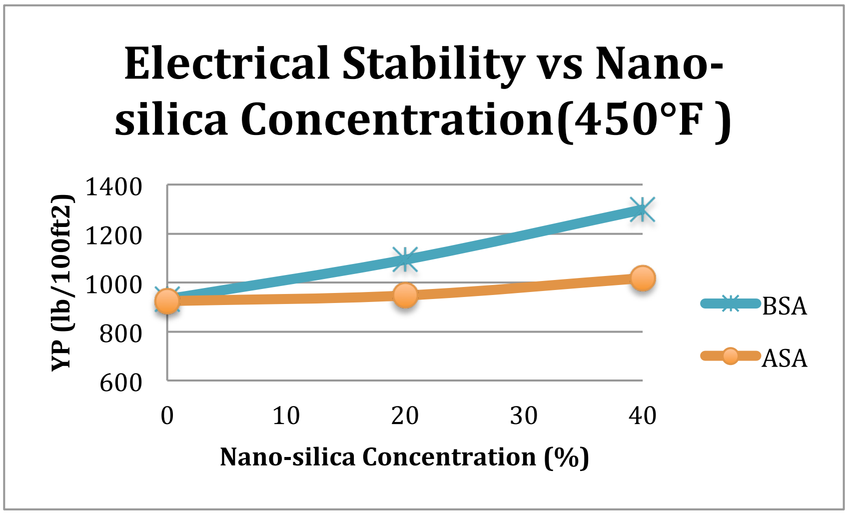

Figure 28: ES vs Nano-silica Concentration @ 17ppg

Figures 26, 27 and 28 shows electrical stability changes with the usage of nano-silica. Electrical stability (ES), measured in volts is the quality of emulsion and oil-wetting qualities of solids of a sample of mud. Nano-particles can replace polymeric surfactants as a water-in-oil emulsion stabilizers it also can be hydrophobic, hydrophilic or amphiphillic (Agharwal, Tran, Soong, Martello, & Gupta, 2011). They can exhibit a large free energy of adsorption and attach themselves to the oil-water interface, especially for particles of intermediate wettability (Agharwal, Tran, Soong, Martello, & Gupta, 2011). Therefore, oil in water emulsions is formed by hydrophilic particles whereas water in oil emulsions is formed by hydrophobic particles.

The acceptable range of values for emulsion stability is above 500 volts. For all samples, the electrical stability is above 500, therefore indicating a stable emulsion and oil wetting properties in the drilling mud since nano-silica is hydrophobic.

vi. Mud Weight

Table 23: Changes in Mud Weight Before & After Static Age

Temperature (°F)	Mud Weight (ppg)					
	Before Static Age			After Static Age		
	Base case	Nano @20%	Nano @40%	Base case	Nano @20%	Nano @40%
275	12	12	12	11.95	11.95	12
350	13.5	13.5	13.5	14.2	13.5	13.5
450	17	17	17	16.95	17.05	17.15

From the Table 23, it is obvious that there are changes in the mud weight either decreasing or increasing after static aging at the given temperatures. This irregularity can be due to not measuring surface mud weight at a constant flowline temperature of 120°F. According to (Godwin, Boniface, & Ogbonna, 2011), geothermal temperature gradient was assumed from the drill floor to the top of the reservoir, which is the maximum pore pressure gradient at 13,8731 ft TVD is 2.7°F/100ft TVD. the hydraulics program calculated that at 120°F the surface mud weight would be the equivalent of the downhole mud weight with the drill floor temperature of 60°F. This statement supports the reason for the need to measure mud weight at a constant flowline temperature of 120ºF, or there will be irregularities in the reading of the mud weight. An increase in the mud weight after static aging can be caused by water evaporation and accumulation of fine solids. Therefore, the surface mud weight can be allowed to fluctuate within a 0.10ppg (0.01 SG) band (Godwin, Boniface, & Ogbonna, 2011). Likewise mud weight can decrease after static aging due to thermal expansion. In conclusion, as long as there is a deviation from the flowline temperature, surface mud weight can fluctuate or drop according to conditions.

4.3.2 Fluid Loss and Barite Sag

i. Filtrate Loss

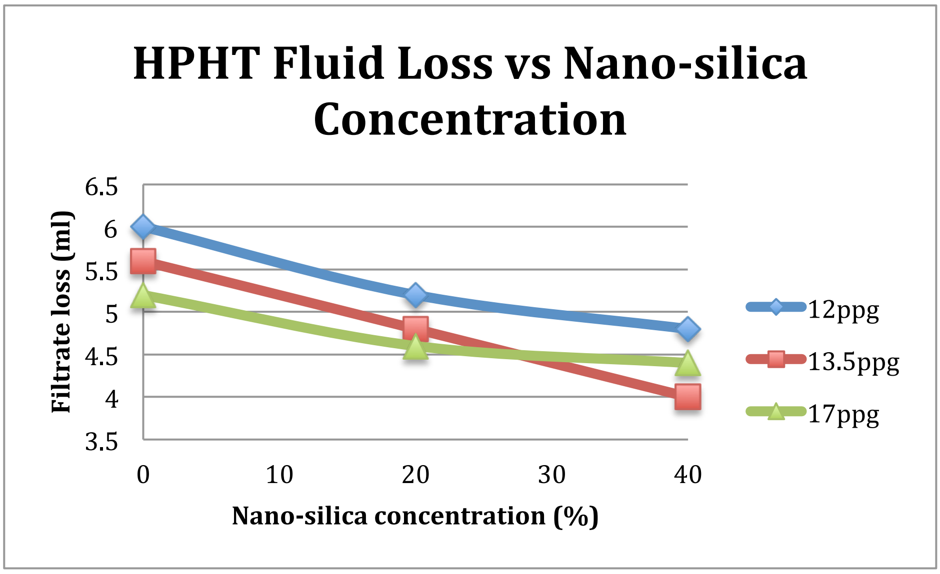

Figure 29: Filtrate Loss vs Nano-silica Concentration

Referring to Figure 26, the graph shows that when nano-silica is added, the filtrate loss decreases. This coincides with the function of nano-silica as a fluid loss agent. The thickness of a filter cake is dependent on the fluid loss into the formation (Holster, Stefano, Riley, & Young, 2012).

Table 24: Comparison of Mud Cake Thickness

Mud Weight (ppg)	Thickness (32inch)		
	Normal Mud	Nano Mud@20%	Nano Mud@40%
12	3/32	2/32	1.5/32
13.5	3.5/32	2/32	1.5/32
17	3/32	2.5/32	1.8/32

From Table 24, as fluid loss decreases, the mud cake thins. The thickness of a mudcake should be less than 2/32 inches, as a mudcake, which is too thick, will narrow wellbore diameter. This causes the drill bit to easily come in contact with the mud cake (stuck). The nano-silica has a diameter of 10-20nm, which is smaller than the pore throats of shale and other formations. Therefore, mud cake can form on the formation as the nano-silica acts as a bridging agent to plug the pores of the formation. Thus, reducing fluid loss of the mud into the formation. This is in line with claims that the application of nanoparticles in drilling fluids is to form a thin layer of non-erodible, and impermeable nanoparticles membrane around the wellbore which prevents clay swelling, spurt loss and mud loss due to circulation (Srivatsa & E, 2010). According to Table 24, the mud cake thickness decreases with the usage of nano-silica. Therefore, proving that nano-silica is useful as a fluid loss agent.

ii. Sag Factor

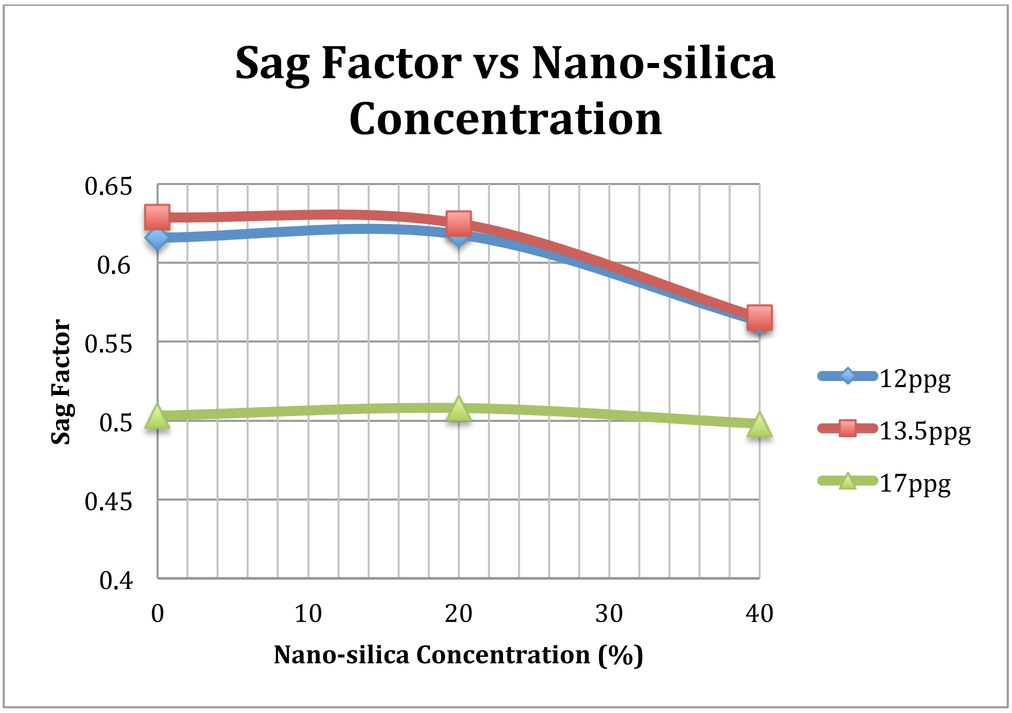

Figure 30: Scatter Plot of Sag Factor vs Nano-silica Concentration

Barite sag occurs when polymeric components of the drilling fluid experience thermal degradation that breaks down emulsion and fluid phase separation (Agharwal, Tran, Soong, Martello, & Gupta, 2011). Figure 30 shows the graph of sag factor against nano-silica concentration. According to the graph, at 20% concentration, the nano-silica does not show any significant effect in sag. At 40% concentration, there seems to be a slight decrease in sag factor. However, this decrease is very little and is only visible in 12ppg and 13.5ppg mud. Aside from that, according to (Godwin, Boniface, & Ogbonna, 2011), the 100rpm dial reading has to be within 35 lb/100ft2 – 42 lb/100ft2 (Shearwater Project). Any reading below 35 lb/100ft2 will result in barite sag. As shown in Table 18, 19, the 100rpm dial reading showed values below 35lb/100ft2, whereas only for Table 20, the 100rpm reading was above 35lb/100ft2. Therefore, from these results, nano-silica does not have an adverse effect on sag at concentration lesser or equal to 40% of fluid loss agent. The nature of nano-silica is as a plugging agent. Figure 31 to Figure 33 shows synthetic based mud mixed at 40% nano-silica concentration for the three given conditions. Figure 34 and Figure 35 shows the mud cake formed from the HPHT filter press at 275°F, 500psi.

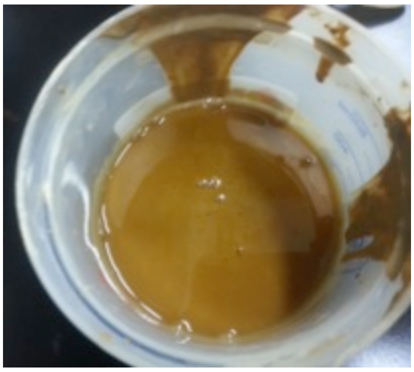

Figure 33: Mud formulated at 275°F

Figure 32: Mud Formulated at 350°F

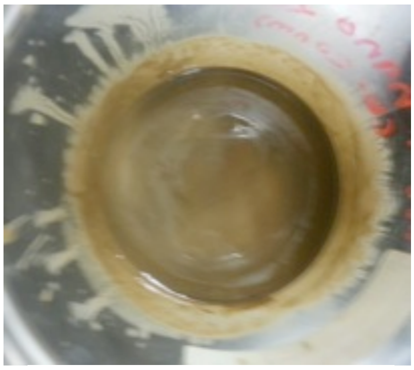

Figure 33: Mud formulated at 450°F

Figure 34: Mudcake for 450°F

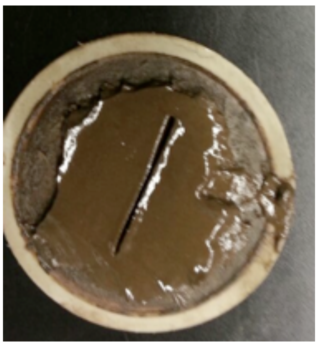

Figure 35: Mudcake for 350°F

CHAPTER 5

5.0 SUMMARY & FUTURE WORK

To summarize, synthetic based muds are currently the drilling fluids of choice due to their high performance in wellbore stability and rate of penetration, especially under High Pressure High Temperature (HPHT) conditions.

Among the most significant problems faced by the oil and gas industry in drilling operations is barite sag, which can lead to fatal incidents such as kick, blowout and complete shutdown of operations. To combat this, static sag and dynamic sag of the mud must be overcome.

Nano-particles are currently the pioneer subjects of research as they have been proven to solve many drilling fluid problems such as fluid loss, wellbore sloughing and formation damage. In fact, addition of nanoparticles has been proven to overcome challenges drilling fluids are unable to.

According to the results, at 20% nano-silica concentration, there is little to no effect on sag. At 40% however, there are slight reductions in 12 and 13.5ppg mud, but the change is not sufficient to conclude that nano-silica has a positive effect on barite sag. However, for fluid loss, nano-silica proves to be a very credible fluid loss agent up until 40% concentration. The nano-silica also has proven to be a functional rheology modifier due to the fact that under its usage, the rheology is stable after static aging.

For future work, the concentration of nano-silica can be increased to to 60%, to observe any further changes in sag, fluid loss and rheology. Furthermore, experimenting on changing the size of the nano-particle from 10-20nm to 5-15nm, and observing any changes in the results at different concentrations can be looked into.

The other option for combatting barite sag would be to change the weighting agent from barite to hematite, ilmenite or manganese tetroxide (micromax) whilst still substituting a fixed percentage of nano-silica as a fluid loss agent. Hematite has a specific gravity higher than 5, whereas barite has a specific gravity of 4 to 4.39. Therefore, for a certain mud weight, formulated mud with hematite will contain less solids by volume which will reduce the sag index of a mud. The nano-silica is not economically feasible to be substituted as a weighting agent.

Table 25: Price Comparison of Nano-silica and Hematite

Material	Price (RM)
Nano-silica (10-20nm)	1660.65 /0.5kg
Hematite	1.80/ 1kg
Barite	0.80/ 1kg

Without a doubt, extensive research on barite sag will always be ongoing as I encountered irregularities in my results or plainly for better understanding. All in all, I look forward to working with my supervisor, Mr. Aslam to make this project successful.

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